NON-PUBLIC?: N
ACCESSION #: 8903170287
LICENSEE EVENT REPORT (LER)

FACILITY
AME: Oconee Nuclear Station, Unit 2 PAGE: 1 OF 8

DOCKET NUMBER: 05000270

TITLE: Turbine/Reactor Trip Due to Management Deficiency and Equipment Failure
EVENT DATE: 02/03/89 LER #: 89-002-00 REPORT DATE: 03/06/89

OPERATING MODE: N POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION
50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
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COMPONENT FAILURE DESCRIPTION:
CAUSE: X SYSTEM: SN COMPONENT: LS MANUFACTURER: M322
REPORTABLE TO NPRDS: No

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On February 3, 1989 at 1545 hours while operating at 100% Reactor Power, the Unit 2 Main Turbine (MT) tripped resulting in an anticipatory Reactor trip. The MT trip was initiated by a loss of 125 VDC power to the Electro Hydraulic Control (EHC) system. The loss of DC power occurred due to the incorrect wiring of a circuit during implementation of a Nuclear Station Modification (NSM). This combined with a pre-existing ground on a conductor supplying power from the EHC to the "2A2" Moisture Separator Reheater high water level switch, caused a loss of 125 VDC power to the EHC. The immediate corrective action was to stabilize the unit at hot shutdown. Supplemental corrective actions included determining the cause of the trip, correcting the wiring problem, and repairing the degraded conductor. The root causes of this trip were: a management deficiency of not properly implementing the independent verification program and of assigning an unqualified person to perform a task; and an equipment failure.
END OF ABSTRACT

BACKGROUND

Duke Power Company endorses a program of Independent Verification. Station Directive 2.2.2, Independent Verification, states that, "In general, Independent Verification is a documented double check of the performance of specific station requirements.". The Directive requires that responsibilities of the individuals performing a procedure step or serving as the verifier of proper step completion must be clearly designated. The Directive also requires both persons performing procedure steps and persons verifying proper completion of steps to be qualified individuals. Qualified individuals are those who possess the knowledge to determine that the correct component is properly identified or that the correct component is properly aligned.

The portion of the Nuclear Station Modification (NSM) that was associated with this unit trip provided direction to personnel to separate the control power to part of the Retransfer to Startup circuit of Emergency Power Switching Logic (EPSL) EIIS:EK! channel A from the control power for SK1 breaker. The Retransfer to Startup functions to transfer back to the Startup Transformer if power from the Keowee hydro is lost. SK1 breaker is the Standby Bus 1 feeder from the Keowee hydro underground emergency power supply. The EPSL in conjunction with its associated circuits, provides a means for assuring that power is supplied to the Main Feeder Buses and therefore to the essential plant loads under accident conditions.

Technical Specification 3.7.2 (b) states that "The circuits or channels of any single functional unit of the EPSL may be inoperable for test or maintenance for periods not exceeding 24 hours" provided that specific operability criteria are met.

EVENT DESCRIPTION

Nuclear Station Modification (NSM) 32565 implementing procedure TN/3/A/2565/0/0 (Install CT-4 and CT-5 meters in the Unit 3 Control Room), was approved on January 9, 1987. Prior to implementing the modification, it was discovered that removal of the control power fuses for either SK1 breaker or SK2 breaker, which was required to install the NSM, resulted in the loss of power to the Retransfer to Startup circuit for Emergency Power Switching Logic (EPSL) channels A and B, respectively. This loss of power to portions of the EPSL left the EPSL in a degraded mode which was undesirable. The NSM was delayed while Design Engineering ii analyzed the problem associated with removal of the control power fuses from either SK1 or SK2 breakers.

After the Design Engineering analysis, revision 4 was incorporated into procedure TN/3/A/2565/0/0 to separate the control circuits for SK1 and SK2 breakers from the Retransfer to Startup circuit of EPSL. The procedure revision was approved on January 26, 1989 and was forwarded to a Construction and Maintenance Department (CMD) Supervisor for implementation. The CMD Supervisor assigned CMD Technicians "A", "B", and "C" to perform portions of the work required by revision 4 to procedure TN/3/A/2565/0/0. The CMD Supervisor and crew began implementing revision 4 of the procedure on January 30, 1989. On January 31, CMD Technicians "A" and "B" were working in EPSL panel, 1EPSLP2. Procedure step 9.1.3.17 required the Technicians to connect conductor 7 to link SK102N. CMD Technician "A" located two spare conductors in 1EPSLP2 and asked CMD Technician "B" to identify conductor 7. CMD Technician "B" correctly identified conductor 7 (color-code white with black tracer) to CMD Technician "A". Because CMD Technician "B" was working in 1EPSLP2 and because of inadequate space for two persons to work in the panel, CMD Technician "A" began work on a different portion of the procedure in a different panel. Approximately thirty minutes later, CMD Technician "A" returned to 1EPSLP2. She mistakenly connected conductor 8 (color-code red with black tracer), with the assumption that conductor 7 was being connected. This left conductor 7 grounded at 1EPSLP2. CMD Technician "B" did not verify that the correct conductor was connected as required by procedure. CMD Technician "A" signed the procedure step as having performed the step and CMD Technician "B" signed the procedure step as having independently verified proper completion of the step. CMD Technician "B" performed both the initial identification of conductor 7 and signed the procedure as the "independent verifier" of step completion. The procedure also I@, required a Quality Assurance (QA) verification of proper completion of steps 9.1.3.17 through 9.1.3.19, which included the step at which the wrong conductor was connected. A QA Inspector verified that only step 9.1.3.19 was properly completed. He did not notice the procedural requirement to check steps 9.1.3.17 and 9.1.3.18 and therefore no QA verification of these two steps was performed.

On February 2, 1989, CMD Technician "C" properly connected the other termination of conductor 7 to the control circuit for the SK1 breaker, according to procedure step 9.1.3.2. This left conductor 7 being connected to ground due to the previous mistake by CMD Technician "A".

On February 3, 1989 at 1059 hours, Operations removed the SK1 breaker control fuses, since the NSM installation required their removal. Removal of the control fuses placed Units 2 and 3 (which were at normal power operation) in a 24 hour Limiting Condition for Operation (LCO) per Technical Specification 3.7.2(b). The CMD Supervisor and CMD Technicians "A", "B", and "C" worked on various parts of the procedure in order to complete the separation of the control power to the Retransfer to Startup circuit of EPSL channel A from the control power for SK1 breaker. After the CMD Supervisor and the CMD Technicians completed the required procedure steps, Operations installed the

SK1 breaker control fuses at 1545 hours. Upon installation of the control fuses, a pathway between the negative ground,

created in 1EPSLP2, and a pre-existing positive ground in the "2A2" Moisture Separator Reheater (MSRH) EIIS:SN! high water level switch EIIS:LS! was established. The pathway was established via the 125 volt DC control power system EIIS:EI!. The positive ground in the "2A2" MSRH switch was a weak ground and therefore had not been detected prior to the NSM wiring discrepancy was introduced to the system. When Operations installed the control fuses at the SK1 breaker, a three amp fuse in the Electro Hydraulic Control (EHC) system EIIS:TQ! was blown. The Unit 2 EHC system, which contains the "2A2" MSRH high water level switch, therefore lost 125 volt DC power. The Unit 2 Main Turbine EIIS:TRB! tripped due to a loss of 125 volt DC power to the EHC system at 1545 hours. The Unit 2 Reactor EIIS:RCT! tripped on a Main Turbine-to-Reactor anticipatory trip also at 1545 hours.

Following the Turbine and Reactor trip, the unit was stabilized at hot shutdown. The Main Feedwater EIIS:SJ! Pumps did not trip, and consequently no actuation of the Emergency Feedwater System EIIS:BA! occurred. In general the plant post trip response was as expected. The average Reactor Coolant System (RCS) EIIS:AB! temperature stabilized at about 556 degrees Fahrenheit approximately six minutes after the trip. RCS pressure ranged from approximately 2150 psig prior to the trip, to a minimum of approximately 1825 psig and to a maximum of approximately 2225 psig. Pressurizer level decreased from the initial pre-trip value of approximately 220 inches to a minimum of approximately 70 inches and then was, maintained at approximately 165 inches by starting the "2B" High Pressure Injection EIIS:BQ! pump. Unit 2 Steam Generator (SG) EIIS:SG! levels were maintained at approximately 27 inches. SG pressure ranged from a pre-trip value of approximately 900 psig to a post-trip maximum value of approximately 1050 psig. The Main Steam EIIS:SB! Relief Valves responded adequately after the trip. There was no apparent RCS leakage induced by this trip and no actuation of either Engineered Safeguards EIIS:JE! systems or Pressurizer relief valves occurred during this incident.

After the Unit trip, troubleshooting began. Both grounds were located by performing resistance checks on various EHC circuits and on the circuits installed by the NSM. At approximately 1900 hours, the incorrect wiring performed at 1EPSLP2 was discovered. The connection of conductor 7 was corrected to match procedure instructions and conductor 8 was reconnected to ground. At approximately 2000 hours, the ground at the MSRH switch was found. Visual inspection indicated that a "2A2" switch conductor had vibrated against a bracket in the switch housing and had worn through the conductor insulation, thereby creating a positive ground. The "2A2" MSRH switch was replaced and the lead-in conductors on all four Unit 2 MSRH high water level switches were replaced. At approximately 0200 hours on February 4, 1989, repairs to the Unit 2 MSRH high water level switches were completed. At approximately 0225 hours, the NSM work associated with the SK1 breaker and EPSL was completed and the LCO was lifted from Units 2 and 3. At 0315 hours, the Reactor was returned to critical and at 0925

hours, the Turbine Generator EIIS:TB! was placed on line.

CONCLUSIONS

Two root causes of the Unit 2 trip were identified as a result of the trip investigation. If any one of the deficiencies had been corrected or had not existed, the trip would likely have not occurred. The two root causes of the trip are described below.

Two causes were attributed to management deficiency and are described in this paragraph. Construction and Maintenance Department (CMD) Technician "B" identified the correct conductor to CMD Technician "A". CMD Technician "A" subsequently connected the wrong conductor to a circuit. CMD Technician "A" then signed the procedure as having performed the step and CMD Technician "B" later signed the procedure as having independently verified proper completion of the step. Performance of both the initial identification of the conductor and the independent verification by CMD Technician "B" violated Station Directive 2.2.2, Independent Verification. Station Directive 2.2.2 requi
es
that two qualified individuals act independently of each other to ensure correct completion of a task. The Directive also requires sign-offs to be made as each step is performed and verified. CMD Supervisor "A" assigned an unqualified individual to perform a task, in order to provide job experience to the unqualified person. Assigning an unqualified individual to actually perform a task for which independent verification is required violates Station Directive 2.2.2. It is noted that CMD management distributed letters dated 12-15-88 and 2-10-89 concerning independent verification to all NSM Supervisors. The letters only briefly describe independent verification and do not specifically explain independent verification requirements. After distribution of the letters, the CMD Supervisor read Station Directive 2.2.2 to his crew and documented the review of the Directive. Because of the above-mentioned violations of Station Directive 2.2.2, made by the CMD Supervisor and CMD Technician "B", and because of the lack of independent verification training provided to CMD personnel, it is concluded that a CMD management deficiency, of less than adequate training provided to personnel, existed.
CMD Technician "A" was not familiar with the conductor identification system used on older cable conductors. She also had not worked near "live" circuitry. Because CMD Technician "A" was not familiar with the conductor

color-code and because she had not worked near "live" circuitry, she had earlier indicated to her Supervisor that she was not qualified to work on many of the systems on which the crew works. The CMD Supervisor, however, believed that CMD Technician "A" needed hands-on experience and assigned her to work on this Nuclear Station Modification (NSM) with CMD Technician "B", who was an experienced technician. In keeping with accepted training standards, the Supervisor should have directed CMD Technician "A" to only observe CMD Technician "B" during the course of implementing the NSM. The Supervisor also should have assigned another

qualified technician to replace CMD Technician "A" and assist CMD Technician "B". It is concluded that the CMD Supervisor made a job assignment to an unqualified individual, which is also categorized as a management deficiency, due to deficient supervision. The failure of the "2A2" Moisture Separator Reheater (MSRH) high water level switch conductor insulation was due to the fact that insulation surrounding a conductor to the "2A2" MSRH switch had vibrated against a bracket in the switch housing. Vibrating against the bracket caused the insulation to degrade and wear through the conductor. Therefore this failure is attributed to an equipment malfunction.

In the course of the investigation of this incident, a deficiency which was not a root cause, but which contributed to the unit trip was identified. The Quality Assurance (QA) Inspector was required to ensure that steps 9.1.3.17 through 9.1.3.19 of procedure TN/3/A/2565/0/0 were properly completed. QA procedure, QCE-3, step 4.4.1a, requires inspectors to ensure that the "correct (number or color-coded) conductor is terminated on the correct terminal". The QA Inspector is a qualified, experienced inspector. He did not recognize that procedure TN/3/A/2565/0/0 required him to verify three steps, although it is clearly indicated in the procedure. It is concluded that procedure steps 9.1.3.17 and 9.1.3.18 were not verified by the QA Inspector as required, due to an inappropriate action of no action taken when required, due to a lack of attention to detail.

In addition to the above discussion concerning the MSRH high water level switch, Licensee Event Report (LER) 270/88-03 was generated to document the investigation into a Unit 2 trip on August 26, 1988. The Main Turbine tripped, which caused an anticipatory Reactor trip, due to the failure of the conductor insulation associated with the "2A2" MSRH high water level switch. Therefore, this event is considered recurring. The failure of the switch conductor was due to embrittlement of the conductor insulation. Repairs made to the switch conductors were expected to have corrected problems with the conductors. Because there was enough slack in the switch conductor, the portion of conductor with brittle insulation was removed and the conductor was reconnected to the switch. It is concluded that the repairs made to the "2A2"

MSRH high water level switch conductors were not as effective as they could have been. If the repairs to the switch conductors had been effective, this trip would not have occurred.

In addition to the above-mentioned August 26, 1988 Unit 2 trip, three other unit trips occurred in the past year; however, none of the corrective actions associated with these trips could have prevented this trip. LER 269/88-09 details a Unit 1 trip that occurred on July 5, 1988. The trip was due to an inappropriate action of using an electrical instrument in the wrong operating mode, combined with a secondary-side valve failure. The corrective actions addressed ensuring that pump timer trip setpoints were adequate, and reviewing the need for

additional preventive maintenance on condensate and feedwater control valves. LER 287/88-06 detailed two Unit 3 trips that occurred on November 14, 1988 which were due to an unknown cause and a ground fault in the Steam Generator high (SG) level trip signal monitor. Corrective actions for the second trip addressed testing the SG high level trip signal monitors that were then in use and those that were in stock prior to use. LER 269/89-01 detailed a Unit 1 trip that occurred on January 2, 1989, that was caused by an inappropriate action of a failure to follow a procedure. The corrective action was to counsel personnel involved with the trip on the need to follow written procedures.

The malfunction of the MSRH high water level trip switch is not NPRDS reportable. The switch assembly is Model 402 manufactured by Magnetrol. No personnel injuries, radiation exposures, or releases of radioactive material resulted from this unit trip.

CORRECTIVE ACTIONS

Immediate

The immediate corrective action was to stabilize the unit at hot shutdown.

Subsequent

1. The causes of the unit trip were determined.
2. The incorrect wiring of the Emergency Power Switching Logic (EPSL) circuitry was corrected.
3. The Units 1 and 2 Moisture Separator Reheater (MSRH) high water level switches were rewired with high temperature application conductors.
4. The Construction and Maintenance Department (CMD) Supervisor was counselled with regard to his error of assigning an unqualified

individual to perform a task.
5. The Quality Assurance Inspector was counselled with regard to his error of missing two required verifications.
6. Revision 5 was incorporated into procedure TN/3/A/2565/0/0 to require continuity checks during subsequent work on the modification with the SK2 breaker.

Planned

1. All Unit 3 MSRH high water level trip switches shall be rewired using high temperature application conductors. Work Requests 50645, 50646, 50647, and 50648 were initiated on 2-4-89 to perform this work.

2. CMD management shall formally train all CMD Nuclear Station Modification personnel with regard to the intent and requirements of Station Directive 2.2.2, Independent Verification. All trained personnel shall be tested to determine training effectiveness.

3. CMD Management shall ensure that all CMD NSM personnel receive an index containing conductor color-codes and associated number-codes. CMD management shall also instruct all CMD NSM personnel with regard to the intent and proper use of the index.

SAFETY ANALYSIS

Following the Turbine and Reactor trip, the unit was stabilized at hot shutdown. Emergency Feedwater was not actuated and the Integrated Control System EIIS:JA! responded properly. The Operations Control Room personnel safely controlled the Unit following the trip. No actuation of Engineered Safeguards systems or Pressurizer relief valves occurred, and no Reactor Coolant System leakage was induced as a result of this trip. While the failure of the Moisture Separator Reheater high water level trip switch was a root cause of this trip, its failure did not reduce the ability of the normal plant systems, or of the plant emergency systems, or of Operations personnel to safely control the plant. Emergency systems were available to assist Operations personnel in controlling the plant, however, the systems were not required to be used and were not activated. The trip response did not degrade plant performance and no safety concerns were generated. The health and safety of the public were not jeopardized as a result of this event.

ATTACHMENT 1 TO 8903170287 PAGE 1 OF 1

Duke Power Company HAL B. Tucker
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DUKE POWER

March 6, 1989

U. S. Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555

Subject: Oconee Nuclear Station
Docket Nos. 50-269, -270, -287
LER 270/89-02

Gentlemen:

Pursuant to 10 CFR 50.73 Sections (a) (1) and (d), attached is Licensee Event Report (LER) 270/89-02 concerning a Unit 2 reactor trip on February 3, 1989.

This report is being submitted in accordance with 10 CFR 50.73 (a) (2) (iv). This event is considered to be of no significance with respect to the health and safety of the public.

Very truly yours,

Hal B. Tucker

PJN/lerf475/td

Attachment

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